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The technical and economic feasibility of biomass gasification for power generation

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This paper reviews the costs and technologies involved in an integrated system for the production of electricity from biomass in general and wood in particular. It first examines the economics of gasification, showing that the potential for this form of renewable energy lies in either processing low-cost wastes or relying on some sort of fiscal incentive, even at relatively large scales of operation and with high-efficiency processes. The paper then considers all the elements required with respect to wood handling and preparation, gasification, gas quality and gas cleaning, and establishes the criteria for their selection for delivery of a clean gas to a gas turbine or engine. Special emphasis has been placed on the technology status and key uncertainties that are considered to be crucial to the success or failure of a biomass-based IGCC system. The main conclusions are that wood handling, storage, drying, comminution and screening are well established and present no uncertainties in operation and performance.The technology of biomass gasifiers is sufficiently advanced to justify a substantial demonstration plant to prove the total IGCC concept and obtain reliable performance data. There are still areas of uncertainty, but these are relatively minor and will not be resolved until and unless a large integrated plant is built. Gas cleaning has been successfully developed in laboratories to the point where large-scale demonstration and long-term operating experience are necessary. This area can be considered the least developed and most likely to create problems in a demonstration plant. Turbine and turbine fuel specifications are imperfectly defined, although engines are known to be more tolerant of contaminated fuel gas.

(Keywords: biomass; gasification; power generation)

Biomass is widely considered to be a major potential fuel and renewable resource for the future. In terms of size of resource, there is the potential to produce at least 50% of Europe's total energy requirement, from purpose-grown biomass using agricultural land no longer required for food, and from wastes and residues from agriculture, commerce and consumers[1,2]. The justification for bioenergy includes[2]:

- security of long-term energy supplies for Europe,
- contributions to the development of industrial markets,
- improvements of the environment by utilizing wastes and residues,
- making a positive contribution to limiting the greenhouse effect,
- better management of surplus agricultural and marginal land,
- provision of opportunities for socio-economic development of the less-developed regions of Europe, particularly towards the south.

As produced, biomass is a solid and is difficult to use in many applications without substantial modification. Conversion to gaseous and liquid energy carriers has many advantages in handling and application.

There is a wide range of processes available for converting biomass and wastes into more valuable fuels. These include biological processes to make ethanol or methane, and thermal processes to make heat, gaseous fuels, liquid fuels and solid fuels, from which a wide variety of secondary products, including electricity, can be produced[1]. Electricity is the industrial sector most likely to benefit from this contribution[3], because of the high added value of electricity compared with other energy forms[4]. This paper focuses on advanced gasification techniques for electricity generation as offering the most developed power generation system based on biomass. A number of recent reviews cover the principles and practice of biomass gasification as applied around the world[5,6].

One of the major problems with biomass is that, as an energy crop, it is labour-intensive to produce, harvest and transport, as it is dispersed over large areas. When it is in the form of wastes, costs are much lower, often negative in the case of domestic solid wastes[6], but the material usually requires extensive processing to make it compatible with the conversion process. There is, therefore, an upper limit to the size of a biomass-fuelled power station, which ranges from 10 to 100 MWe according to the location.

ECONOMICS

Since economic implications determine the rate of development and rate of implementation of emerging technologies such as biomass gasification, the economics are presented first. The wide range of justifications for bio-energy listed above mean that orthodox accounting is not sufficient. Even the addition of both quantified and unquantified incentives such as carbon taxes and

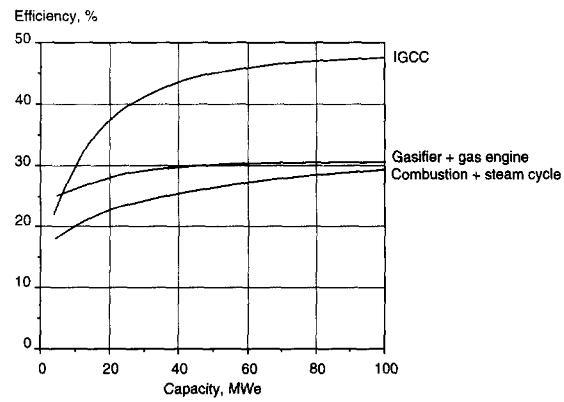

Figure 1 Efficiencies of different biomass power generation systems

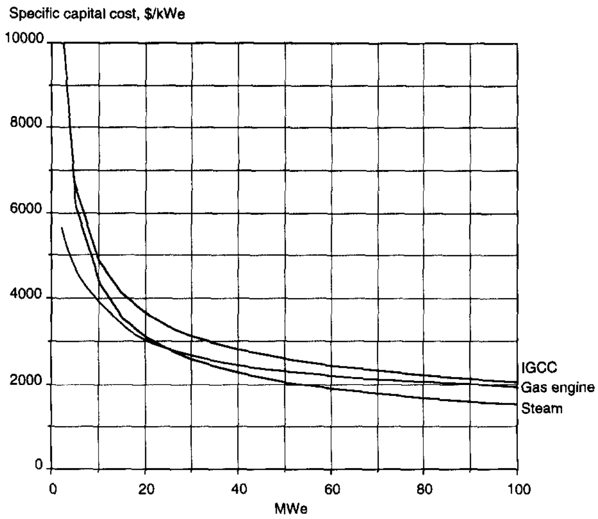

Figure 2 Specific capital costs of different biomass power generation systems, 1994 basis

agricultural policy adjustments may not be sufficient to turn a marginally attractive project into one where the rewards justify the risks, but application of such incentives can make such projects sufficiently close to commercial acceptability for further development to be supported, which will reduce the technical risks and enable the project development cycle to move forward. After discussion of the economic aspects, the technologies are described and the technical uncertainties identified and reviewed.

Power generation system status

There are several ways of producing electricity by thermal conversion of biomass: pressurized gasification with a gas turbine in a combined cycle mode, atmospheric gasification with a turbine or an engine, and orthodox combustion with a Rankine cycle. The efficiencies of these different biomass power generation systems are compared in *Figure 1* from biomass delivered to the conversion plant to power exported to the grid. The specific capital costs of the same biomass power generation systems are shown in *Figure 2* and the electricity generation costs in *Figures 3, 4* and *5* for different capacities and feed costs[7]. Data have been derived from ongoing in-house research and are internally consistent and validated.

Pressurized gasification in a combined cycle mode is being demonstrated in the Varnamo plant in Sweden with an Ahlstrom gasifier and a European Gas Turbine 4 MWe machine operating in combined cycle and cogeneration mode[6]. Atmospheric gasification with an engine has been demonstrated at 500 kWe at TPS in Sweden[6], and there has been extensive experience of such systems around the world from 10 to 300 kWe[5]. The European Union is planning to support the demonstration of three biomass-based (short-rotation foresty) IGCC plants ranging from 7 to 12 MWe, one pressurized and two atmospheric. IGCC technology is relatively well developed, with around eight systems potentially available commercially. The greatest area of uncertainty is performance and reliability of the gas cleaning systems.

Combustion with a Rankine cycle for power generation from biomass is well established, with hundreds of plants operating in the USA in the 15 to 50 MWe size range[8].

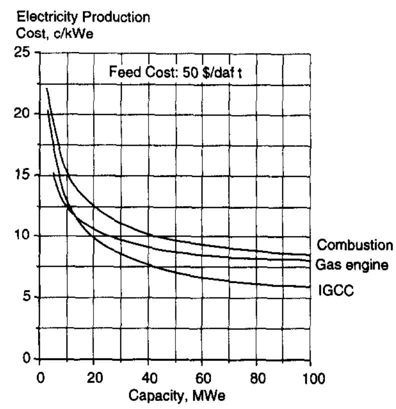

Figure 3 Cost of electricity from different biomass power generation systems vs. capacity, 1994 basis

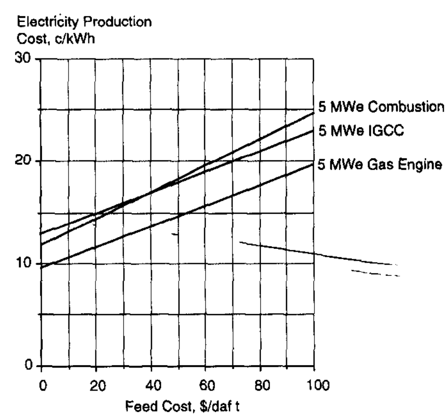

Figure 4 Electricity cost vs. feed cost for different biomass power generation systems at 5 MWe, 1994 basis

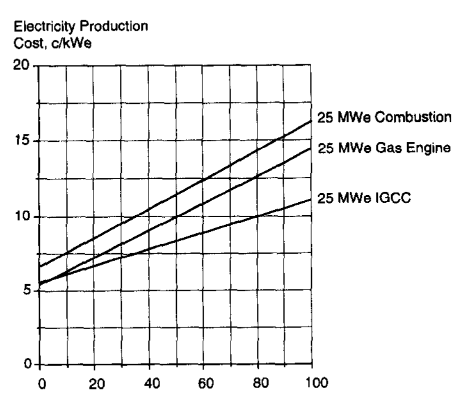

Figure 5 Electricity cost vs. feed cost for different biomass power generation systems at 25 MWe, 1994 basis

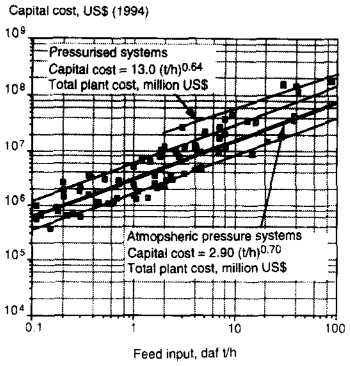

Figure 6 Installed plant costs for gasification systems, 1994 basis

Most are based on conventional technology using either fixed beds or grates, or, more recently, fluidized and circulating fluid bed systems.

There is a further power generation technology which is relatively new and unproven: flash pyrolysis to liquids that are fired into an engine or turbine. Flash pyrolysis is a fairly new technology that gives yields of liquids up to 83 wt% of dry feed[9]. Some preliminary tests have been carried out with an engine which show that the concept is feasible, but no long-term or large-scale tests have been carried out. Similar tests have been carried out on a turbine with similar results; work is proceeding in both areas. There are major attractions in being able to decouple fuel production from power generation, which cannot be achieved in gasification and combustion systems. This offers possibilities for fuel production that is remote from the power requirement, or power generation that is remote from the biomass supply. A number of problems have been identified, such as alkali metals and temperature stability, and there is some uncertainty with this route, although on the evidence to date it is shown as economically very attractive.

A biomass gasification-to-electricity system consists of three main areas: feed pretreatment, gasifier and gas clean-up, and turbine or engine. These are now summarized and the economically significant aspects highlighted.

Feed pretreatment

Biomass is prepared in the forest usually as chips, although bundles from short-rotation forestry and whole logs from conventional forestry may be delivered in some circumstances. Annual crops would be delivered in bundles (for example from miscanthus or sorghum), as bales (e.g. from straw), or possibly chopped (from any crop). This material has to be received, handled, stored and processed prior to gasification, and this front-end system is described in detail later (see Status and technical uncertainties). The technology is well established and available for chips, although there is almost no experience with either large-scale or long-term production of short-rotation coppice for energy purposes. This is partly why the EU is sponsoring three large IGCC demonstration plants based on biomass. Similarly there are no robust data on the energy balances for biomass production beyond claims that the energy ratio (energy out/energy in) is between 15 and 35, i.e. a biomass production energy efficiency of 93 to 96%. This includes all transport, fertilizer and processing costs up to the conversion plant gate.

Once within the conversion plant, the feed material has to be processed (see later). The capital cost of the whole pretreatment part of the system is about US$600/kWe at 20 MWe, and offers some economy of scale, falling to around US$300/kWe at 100 MWe. There are few data available on performance or cost apart from a design and costing carried out for the IEA Bioenergy Agreement[10]; costs ranged from 200 to 500 US$/kWe at 1000 t day^{-1} dry feed (equivalent to about 60 MWe) according to design and specification.

Gasifiers

Gasification plant capital costs have been collated and normalized to a mid-1994 basis in Western Europe[6]. The data cover the system from reception of feed biomass to delivery of a clean gas for power generation. The results are summarized in *Figure 6*, which shows a clear difference in capital costs between pressurized and atmospheric systems that may be accounted for by the significantly higher equipment and construction costs of pressure equipment. Although pressurized systems have a lower volume, there is relatively little reaction-kinetic or thermodynamic advantage resulting from pressurized operation because biomass is so reactive, unlike coal, for which higher pressures offer considerable performance advantages. There is also a considerable spread of data in *Figure 6*, particularly for atmospheric units, for which upper and lower boundaries of costs are indicated. This is explained in part by variations in scope — what costs and also what units are included, such as feed handling and pretreatment, and in part by cost variations in different locations resulting from varying labour rates and regional legislation.

Electricity generation

Electricity generation is carried out by internal and external combustion engines or turbines. Fuel cells have been proposed, but considerable development work is needed before these can be seriously considered. Data are available for gas turbines and engines operating on fossil fuels, but few robust data have been found on biomass-derived fuel gas machines, owing to the unknown costs of modification and maintenance and machine life. Manufacturers are therefore very reluctant to quote costs for supply, although a number of machines will be installed over the next few years.

System costs

A major IGCC project of 27 MWe is being evaluated for Brazil. The initial capital cost estimates were around US$2750/kWe in 1992. It is hoped that careful design and R&D will bring this down to around $1500–1600 for the tenth plant, owing to the 'learning effect' described below[4]. Other cost data have been analysed and representative figures for first plant are included in *Table 1* and *Figure 7*, which clearly show the higher cost of pressurized systems and the potential for cost reduction from learning and replication.

To identify the significant cost elements in a total system, an approximate breakdown of the main steps in an atmospheric air-blown gasification process of 10 MWe is given in *Table 2*. It must be emphasized that these are only indicative costs to establish order of magnitude and relative costs between the main components.

Table 1 IGCC system capital costs, 1994 basis

System	MWe	Cost (US$/kWe)	Basis	Status (plant no.)
IGCC	27	2 750	Brazil GEF[a]	1st
IGCC	27	1 500	Brazil	10th
IGCC	5	3 600	Atmospheric gasifier	1st
IGCC-CHP[b]	6	6 000	Pressure gasifier	1st
IGCC	7	14 000	Pressure gasifier	1st
IGCC	8	5 000	Atmospheric gasifier	1st
IGCC	12	4 200	Atmospheric gasifier	1st
IGCC-CHP	16	3 200	Atmospheric gasifier	1st
IGCC-CHP	55	4 200	Pressure gasifier	1st

[a]GEF = Global Environment Fund
[b]CHP = combined heat and power

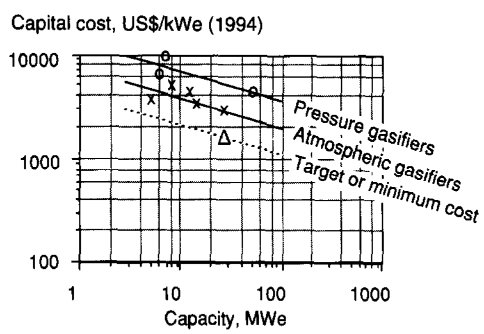

Figure 7 Installed IGCC capital costs, 1994 basis

It is well known that after the first plant of a new technology has been built, subsequent plants will cost less owing to 'learning effects' — the knowledge and experience gained in building and operating this first plant will improve the design and operation of subsequent plants. For example, this effect has been widely applied to chemicals production costs, for which learning effects of 15 to 20% are common[11], defined as the cost reduction when production is doubled. A similar effect is found for capital costs of novel process plant and application of the 20% learning effect results in a potential cost reduction of 50% by the time the tenth plant is built. There is only empirical evidence of this effect, but it is widely known and is now being increasingly applied to examination of the replication potential of energy from biomass projects, for example in the justification for the Brazilian power project[4].

GASIFICATION

Thermochemical gasification is the conversion by partial oxidation at elevated temperature of a carbonaceous feedstock such as biomass or coal into a gaseous energy carrier. This contains carbon monoxide, carbon dioxide, hydrogen, methane, trace amounts of higher hydrocarbons such as ethane and ethene, water, nitrogen (if air is used as the oxidizing agent) and various contaminants such as small char particles, ash, tars and oils. The partial oxidation can be carried out using air, oxygen, steam or a mixture of these.

Air gasification produces a poor-quality gas in terms of heating value (4–7 MJ m_s^{-3} higher heating value) which is suitable for boiler, engine and turbine operation, but not for pipeline transportation due to its low energy density. Oxygen gasification produces a better-quality gas (10–18 MJ m_s^{-3} higher heating value) which is suitable for limited pipeline distribution and for use as sythesis gas for conversion, for example, to methanol and gasoline. Gas of this quality can also be produced by pyrolytic or steam gasification, with the process energy being supplied by combustion of by-product char in a second reactor, e.g. a twin fluid bed system. Gasification with air is the more widely used technology since this avoids the costs and hazards of oxygen production and usage associated with oxygen gasification, and the complexity and cost of multiple reactors in steam or pyrolytic gasification when two reactors are required.

Principles

Gasification occurs in sequential steps:

- drying — to evaporate moisture,
- pyrolysis — to give gas, vaporized tars or oils and a solid char residue,
- gasification — or partial oxidation of the solid char, pyrolysis tars and pyrolysis gases.

When a solid fuel is heated to 300–500°C in the absence of an oxidizing agent it pyrolyses to solid char, condensable hydrocarbons or tar, and gases. The relative yields of gas, liquid and char depend mostly on the rate of heating and the final temperature. Generally pyrolysis proceeds much more rapidly than gasification, and the latter is thus the rate-controlling step. The gas, liquid and solid products of pyrolysis then react with the oxidizing agent — usually air — to give permanent gases (CO, CO_2, H_2) and lesser quantities of hydrocarbon gases. Char gasification is the interactive combination of several gas–solid and gas–gas reactions in which solid carbon is oxidized to carbon monoxide and carbon dioxide, and hydrogen is generated through the water-gas shift reaction. The gas–solid reactions of char oxidation are the slowest and limit the overall rate of the gasification process. Many of the reactions are catalysed by the alkali metals present in wood ash, but still do not reach equilibrium. The gas composition is influenced by many factors such as feed composition, water content, reaction temperature, and the extent of oxidation of the pyrolysis products.

Not all the liquid products from the pyrolysis step are completely converted owing to the physical or geometrical limitations of the reactor and the chemical limitations of the reactions involved, and these give rise to contaminant tars in the final product gas. Owing to the higher temperatures involved in gasification compared

Table 2 Approximate atmospheric pressure IGCC plant cost analysis at 10 MWe

Item	US$ million	%
Reception, storage and handling	2.5	12.5
Comminution and screening	1.5	7.5
Drying	2.5	12.5
Gasification	9.0	45.0
Heat recovery	1.5	7.5
Tar cracking and/or removal	3.0	15.0
Subtotal	20.0	100.0
Power generation, gas and steam turbines	15.0	
TOTAL	35.0	

Table 3 Gasification reactor types

Fixed bed	
Downdraft	solid moves down, gas moves down
Updraft	solid moves down, gas moves up
Concurrent	solid and gas move in same direction — downdraft
Countercurrent	solid and gas move in opposite directions — updraft
Cross-current	solid moves down, gas moves at right angles
Variations	stirred bed; two-stage gasifier
Fluid bed	
Single reactor	low gas velocity, insert solid stays in reactor
Fast fluid bed	inert solid is elutriated with product gas and recycled
Circulating bed	inert solid is elutriated, separated and recirculated; sometimes also refers to fast fluid bed or twin-reactor systems
Entrained bed	usually no inert solid; highest gas velocity of lean-phase systems; can be run as a cyclonic reactor
Twin reactor	steam gasification and/or pyrolysis occurs in the first reactor; char is burned in the second reactor to heat the fluidizing medium for recirculation; either can be any type of fluid bed, although the combustor is often a bubbling fluid bed
Moving bed	mechanical transport of solid; usually lower-temperature processes; includes multiple heart, horizontal moving bed, sloping hearth, screw/auger kiln
Other	
Rotary kiln	good gas-solid contact; careful design needed to avoid solids carryover
Cyclonic reactors	high particle velocities give high reaction rates
Vortex reactors	similar to cyclonic reactors

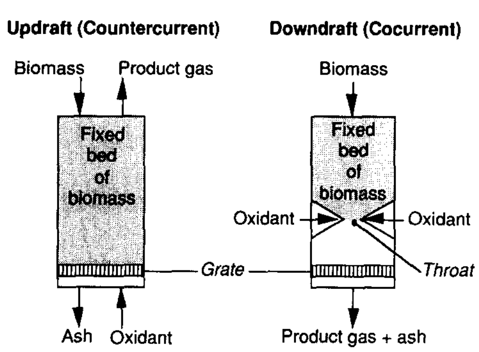

Figure 8 Fixed-bed gasifier types

with pyrolysis, these tars tend to be refractory, i.e. very unreactive, and are difficult to remove by thermal, catalytic or physical processes. This aspect of tar cracking/removal in gas cleanup is one of the most important technical uncertainties in implementation of gasification technologies and is discussed below.

Gasification technology

A range of reactor configurations has been developed, as shown in *Table 3*, *Figures 8* to *10* show the configurations of the more common gasifier types. *Table 4* summarizes the key features of each reactor type, *Table 5* summarizes the other relative advantages and disadvantages of the most common gasifier types, and *Table 6* summarizes performance data for most gasifier types. Each main type of gasifier configuration is described below, with significant features and limitations highlighted. There is a recent review of all these gasifiers[6].

Downdraft gasifiers. The downdraft gasifier (*Figure 8*) features concurrent flow of gases and solids through a descending packed bed which is supported across a constriction known as a throat, where most of the gasification reactions occur. The reaction products are intimately mixed in the turbulent high-temperature region around the throat, which aids tar cracking. Some tar cracking also occurs below the throat on a residual charcoal bed, where the gasification process is completed. This configuration results in a high conversion of pyrolysis intermediates and hence a relatively clean gas.

Downdraft gasification is simple, reliable and proven for certain fuels, such as relatively dry (up to ~30 wt% moisture) blocks or lumps with a low ash content (< 1 wt%) and containing a low proportion of fine and coarse particles (not smaller than ~1 cm and not larger than ~30 cm in the longest dimension). Owing to the low content of tars in the gas, this configuration is generally favoured for small-scale electricity generation with an internal combustion engine. The physical limitations of the diameter and particle size relation mean that there is a practical upper limit to the capacity of this configuration of ~500 kg h^{-1} or 500 kWe.

A relatively new concept of stratified or open-core downdraft gasifier has been developed, in which there is no throat and the bed is supported on a grate. This was first devised by the Chinese for rice husk gasification and further developed by Syngas Inc.[12] from work carried out at the Solar Energy Research Institute (now the National Renewable Energy Laboratory — NREL)[13].

Updraft gasifiers. In the updraft gasifier (*Figure 8*), the downward-moving biomass is first dried by the

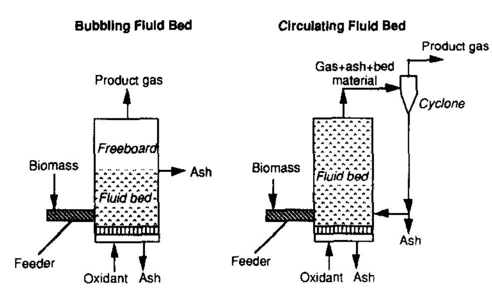

Figure 9 Principles of single and circulating fluid bed gasifiers

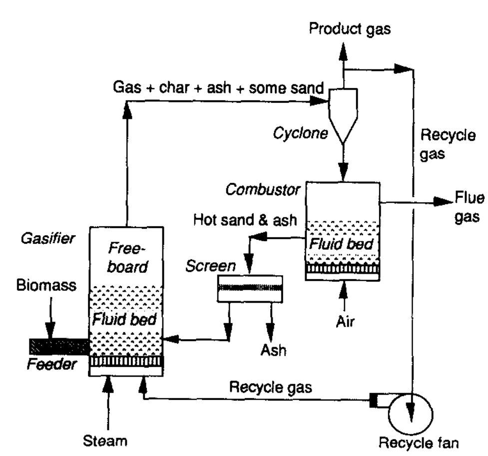

Figure 10 Principle of twin fluid bed gasifier

Table 4 Gasifier characteristics

Downdraft
- Simple, reliable and proven for certain fuels
- Relatively simple construction
- Close size specification required on feedstock
- Low moisture fuels required
- Relatively clean gas is produced
- High exit gas temperature
- Possible ash fusion and clinker formation on grate
- Low specific capacity
- High residence time of solids
- Potential high carbon conversion
- Low ash carryover
- Limited turndown
- High conversion efficiency
- Very limited scale-up potential with low maximum size

Updraft
- Very simple and robust construction
- Low exit gas temperature
- High thermal efficiency
- Product gas is very dirty with high levels of tars
- High carbon conversion
- Low ash carryover
- High residence time of solids
- Product gas suitable for direct firing
- Extensive gas cleanup needed for engines
- Good turndown
- Very high conversion efficiency
- Good scale-up potential

Bubbling fluid bed
- Tolerates variations in fuel quality
- Greater tolerance to particle size range than fixed beds
- Low feedstock inventory
- Good temperature control and high reaction rates
- Good gas–solid contact and mixing
- In-bed catalytic processing possible
- Moderate tar levels in product gas
- Higher particulates in the product gas than fixed beds
- Carbon loss with ash
- Can operate at partial load
- Limited turn down
- Easily started and stopped
- High conversion efficiency
- High specific capacity
- Good scale-up potential

Circulating fluid bed
- Relatively simple construction
- Greater tolerance to particle size range than fixed beds
- Good temperature control and high reaction rates
- In-bed catalytic processing not possible
- Moderate tar levels in product gas
- High carbon conversion
- Good gas–solid contact and mixing
- Operation can be more difficult than fixed beds
- High specific capacity
- High conversion efficiency
- Limited turndown
- Very good scale-up potential

Entrained flow
- Costly feed preparation needed for woody biomass
- Low feedstock inventory
- High temperatures give good gas quality
- Materials of construction problems with high temperatures
- Good gas–solid contact and mixing
- Produces very low-tar gas with little methane
- Carbon loss with ash
- Potential slagging of ash
- High conversion efficiency
- High specific capacity
- Only suitable for large scale applications above $\sim 10\,t\,h^{-1}$
- Limited turndown
- Very good scale-up potential

Twin fluid bed
- Complex and hence costly design
- Gas has moderate tar levels requiring cracking or cleaning
- Catalyst can be added to fluid bed
- Good gas–solid contact and mixing
- MHV gas produced using air and without requiring oxygen
- Relatively low efficiency
- High specific capacity
- Complexity requires large capacities of $>5\,t\,h^{-1}$ for viability
- Scale-up possible but complex

Table 5 Typical gasifier characteristics (all air-blown)

	Temperature (°C)							MWe[a]	
	Reaction	Exit gas	Tars	Particulates	Turn-down	Scale-up ability	Current capacity max. ($t\,h^{-1}$)	Min.	Max.
Fixed bed[b]									
Downdraft	1000	800	v. low	moderate	good	poor	0.5	0.1	1
Updraft	1000	250	v. high	moderate	good	good	10[c]	1	10
Cross-current	900	900	v. high	high	fair	poor	1	0.1	2
Fluid bed									
Single reactor	850	800	fair	high	good	good	10[c]	1	20
Fast fluid bed	850	850	low	v. high	good	v. good	20[c]	2	50
Circulating bed	850	850	low	v. high	good	v. good	20[c]	2	100
Entrained bed	1000	1000	low	v. high	poor	good	20[c]	5	100
Twin reactor	800	700	high	high	fair	good	10[c]	2	50
Moving bed									
Multiple hearth	700	600	high	low	poor	good	5	1	10
Horizontal moving bed	700	600	high	low	fair	fair	5	1	10
Sloping hearth	800	700	low	low	poor	fair	2	0.5	4
Screw/auger kiln	800	700	high	low	fair	fair	2	0.5	4
Other									
Rotary kiln	800	800	high	high	poor	fair	10[c]	2	30
Cyclone reactors	900	900	low	v. high	poor	fair	5	1	10

[a] At 36% overall efficiency
[b] Sometemes called moving bed; the biomass does move slowly
[c] Capable of scale-up to higher levels

Table 6 Product gas characteristics

Gasifier type	Capacity (t h^{-1})	Capacity (MWe)[a]	Feed specificity[b]	HHV (MJ m_s^{-3})	Gas quality[c]	Outlet temp. (°C)
Downdraft, air	0.1–0.7	0.2–1.4	1	4–6	4	700–1000
Downdraft, oxygen	1–5	2–10	1	9–11	4	700–1100
Updraft, air	0.5–10	1–20	2	4–6	3	100–400
Updraft, oxygen	1–10	2–10	2	8–14	3	100–700
Single fluid bed, air	0.5–15	1–30	4	4–6	3	500–900
Single fluid bed, oxygen	2–10	4–20	4	8–14	3	700–1100
Single fluid bed, steam	1–10	2–20	4	12–18	3	700–900
Circulating fluid bed, air	2–20	4–40	3	5–6.5	2	700–1100
Circulating fluid bed, oxygen	2–20	4–40	3	10–13	3	800–1200
Twin fluid bed	1–10	2–20	4	13–20	3	750–1000
Cross-flow, air	0.1–0.5	0.2–1	2	4–6	1	600–900
Horizontal moving bed, air	0.5–5	1–10	5	4–6	2	300–800
Rotary kiln, air	1–10	2–20	5	4–6	2	600–1000
Multiple hearth	1–20	2–40	3	4–6	2	400–700
Secondary processing	–		–	–	5	1000–1200

[a]Conversion at 36% overall efficiency
[b]1, Most specific; 5, least specific
[c]Tars and particulates in raw gas: 1, worst; 5, best

upflowing hot product gas. After drying, the solid fuel is pyrolysed, giving char which continues to move down to be gasified, and pyrolysis vapours which are carried upward by the upflowing hot product gas. The tars in the vapour either condense on the cool descending fuel or are carried out of the reactor with the product gas, contributing to its high tar content[14]. The extent of this tar 'bypassing' is believed to be up to 20% of the pyrolysis products[15]. The condensed tars are recycled back to the reaction zones, where they are further cracked to gas and char. In the bottom gasification zone the solid char from pyrolysis and tar cracking is partially oxidized by the incoming air or oxygen. Steam may also be added to provide a higher level of hydrogen in the gas.

The product gas from an updraft gasifier thus contains a significant proportion of tars and hydrocarbons which contribute to its high heating value. The fuel gas requires substantial cleanup if further processing is to be performed. The principal advantages of updraft gasifiers are their simple construction and high thermal efficiency: the sensible heat of the gas produced is recovered by direct heat exchange with the entering feed, which thus is dried, preheated and pyrolysed before entering the gasification zone. In principle, there is little scaling limitation, although no very large updraft biomass gasifiers have been built.

Fluid bed gasifiers. These are a more recent development that takes advantage of the excellent mixing characteristics and high reaction rates of this method of gas–solid contacting. The fluidizing material is usually silica sand, although alumina and other refractory oxides have been used to avoid sintering, and catalysts have also been used to reduce tars and modify product gas composition[8]. Although only recently applied to biomass, there are over 50 years' experience with peat. Fluidized bed reactors are the only gasifiers with isothermal bed operation. A typical operating temperature for biomass gasification is ~800–850°C. Most of the conversion of the feedstock to product gas takes place within the bed; however, some conversion to product gas continues in the freeboard section owing to reactions of entrained small particles and particularly thermal tar cracking. In most cases carbon conversion approaches 100%, unless excessive carryover of fines takes place, which will occur with a top feeding configuration. The bubbling fluid bed gasifier tends to produce a gas with a tar content between that of the updraft and downdraft gasifiers. Some pyrolysis products are swept out of the fluid bed by gasification products, but are then further converted by thermal cracking in the freeboard region (see *Figure 9*).

Loss of fluidization due to bed sintering is one of the commonly encountered problems, depending on the thermal characteristics of the ash. Alkali metal compounds from the biomass ash (such as sodium and potassium carbonate) form low-melting eutectics with the silica in the sand which is the usual fluidizing medium. This results in agglomeration and bed sintering with eventual loss of fluidization. However, the inherently lower operating temperature of a fluid bed and its inherently better temperature control provide an acceptable control measure for many biomass materials. Municipal solid waste (MSW) is a notable exception, owing to its glass content. With biomass of high ash/inerts content it may be better to use alumina or even a metal compound such as chromite sand.

However, loss of carbon in entrained ash can become significant, and fluidized beds are not economical for small-scale applications. Moreover, they incur higher operating (i.e. compression) costs. Fluidized bed gasifiers have the advantage that they can readily be scaled up with considerable confidence. Only the fuel distribution becomes problematical in large beds, although multiple feeding is an acceptable solution. Alternative configurations such as twin-bed systems and circulating fluidized beds are also available to suit almost every type of feedstock or thermochemical process. In catalytic thermochemical processes the bed material can be replaced by the catalyst, thereby avoiding costly impregnation techniques. Alternatively a second catalytic reactor can be added[7], as in the TPS (Thermal Processing Systems, Sweden) system[6] or a thermal cracking reactor can be added, as in the Steine Industrie gasifier[16].

Fluidized beds provide many features not available in the fixed-bed types, including high rates of heat and mass transfer and good mixing of the solid phase, which means that reaction rates are high and the temperature is more or less constant in the bed. A relatively small particle size compared with that in dense-phase gasifiers is desirable, and this may require additional size reduction. The ash is elutriated and is removed as fine particulates entrained in the off-gas.

Circulating fluid bed gasifiers. The fluidizing velocity in the circulating fluid bed is high enough to entrain large amounts of solids with the product gas (see *Figure 9*). These systems were developed so that the entrained material is recycled back to the fluid bed to improve the carbon conversion efficiency compared with the single fluid bed design. A hot raw gas is produced which, in most commercial applications to date, is used for close-coupled process heat or in boilers to recover the sensible heat in the gas[6]. This configuration has been extensively developed for woodwaste conversion in pulp and paper mills for firing lime and cement kilns[17,18] and steam-raising for electricity generation.

Entrained bed gasifiers. In entrained flow gasifiers, no inert material is present but a finely reduced feedstock is required. Entrained bed gasifiers operate at much higher temperatures of ~1200–1500°C, depending on whether air or oxygen is employed, and hence the product gas has low concentrations of tars and condensable gases. However, this high-temperature operation creates problems of materials selection and ash melting. Conversion in entrained beds effectively approaches 100%. There is little experience with biomass in such systems.

Twin fluid bed gasifiers. These are used to give a gas of higher heating value from reaction with air than is obtained from a single air-blown gasifier (see *Figure 10*). The gasifier in effect is a pyrolyser, heated with hot sand from the second fluid bed, which is heated by burning the product char in air before recirculation to the first reactor. Steam is also usually added to encourage the shift reaction to generate hydrogen and to encourage carbon–steam reactions. Product quality is good from a heating-value viewpoint, but poor in terms of tar loading from the essentially pyrolytic process.

Comparison of pressurized and atmospheric operation. The relative advantages and disadvantages in terms of cost and performance of pressurized gasification systems have not been fully resolved, as is evidenced by the short list for the Brazilian IGCC project, which contains one atmospheric and one pressurized system.

Pressurized gasifiers have the following significant features:

(1) Feeding is more complex and very costly, and has a high inert gas requirement for purging.
(2) Capital costs of pressure equipment are much higher than for atmospheric equipment, although equipment sizes are much smaller[6]. This was discussed above (*Table 1, Figure 7*): pressurized gasification systems can cost up to four times as much as atmospheric systems at power outputs up to 20 MWe. This disadvantage is countered by the higher efficiency, and this effect becomes significant at ~30–50 MWe, above which pressure systems are believed likely to be more economic than atmospheric systems.
(3) Gas is supplied to the turbine at pressure, removing the need for gas compression and also permitting relatively high tar contents in the gas; such tar needs to be completely burned in the turbine combustor.
(4) Hot gas cleanup with mechanical filters (such as sintered metal or ceramic candles) is usually used, which reduces thermal and pressure energy losses and in principle in simpler and of lower cost than are scrubbing systems.
(5) Overall system efficiency is higher owing to retention of sensible heat and chemical energy of tars in the product gas and the avoidance of a fuel gas compression stage ahead of the turbine. The only significant energy losses are to the environment and in provision of inert gas to the pressure feeders, and these can be as low as 5–8%, giving an energy conversion efficiency for the gasifier itself of 92–95%. A corresponding atmospheric gasifier with water scrubbing and product gas compression would have an analogous efficiency as low as 80–85%, depending on capacity and design.

Atmospheric gasifiers have the following significant features:

(1) For gas turbine applications the product gas is required to be sufficiently clean for compression before the turbine. Suggested specifications are given later. For engine applications the gas quality requirements are less onerous and pressure is not required.
(2) Atmospheric systems have a potentially much lower capital cost at smaller capacities of below ~30 MWe as discussed above[6].

Gas compositions and heating values are not significantly different for either system.

Products of gasification

The products of gasification vary according to the reactor configuration and oxidant used. Ideally, there is complete conversion of all tars, hydrocarbons and char in the gasifier to give fuel gas. However, reactor design can give rise to incomplete oxidation, the extent of which is mostly determined by reactor geometry. Typical gasifier features are summarized in *Table 5* and compared in *Table 4*. Product characteristics are summarized in *Table 6* and typical gas compositions in *Table 7*.

Current status

Table 8 summarizes all known recent and current activities on biomass gasification around the world that are either at a demonstration or commercial scale or have been developed to a point where they can, in principle, be demonstrated[6]. This is included to show the extent of activity that has taken place over the last 5 years. The table identifies those processes (in bold typeface) that have either been developed to a point where they can be potentially implemented at a substantial scale of ≥5 MWe or are being seriously considered. From this list, the major gasification groups are shown in *Table 9* according to the technologies that are being developed.

Table 7 Typical product gas characteristics from different gasifiers

	Gas composition (vol.%, dry)					HHV	Gas quality	
	H_2	CO	CO_2	CH_4	N_2	(MJ m_s^{-3})	Tars	Dust
Fluid bed, air-blown	9	14	20	7	50	5.4	fair	poor
Updraft, air-blown	11	24	9	3	53	5.5	poor	good
Downdraft, air-blown	17	21	13	1	48	5.7	good	fair
Downdraft, oxygen-blown	32	48	15	2	3	10.4	good	good
Multi-solid fluid bed	15	47	15	23	0	16.1	fair	poor
Twin fluidized bed gasification	31	48	0	21	0	17.4	fair	poor
Pyrolysis (for comparison)	40	20	18	21	1	13.3	poor	good

Table 8 Recent and current gasification processes[a]

Organization	Country	Process type
Aerimpianti (TPS process)	Italy	Circulating fluid bed
Ahlström	**Finland**	**Atmospheric circulating fluid bed**
Arizona State University	USA	Twin fluid bed
Battelle Columbus	**USA**	**Fast fluid bed**
Battelle PNL	USA	Wet gasification
Bioflow (Ahlström/Sydkraft)	**Finland**	**Pressure circulating fluid bed**
Bioneer	**Finland**	**Updraft**
Ebara	**Japan**	**Twin fluid bed**
EFEU	Germany	Fixed bed with cracking
General Electric	USA	Updraft
Gotaverken	**Sweden**	**Circulating fluid bed**
Hitachi	**Japan**	**Updraft**
HTW	**Finland**	**Pressure oxygen fluid bed**
IGT	**USA**	**Pressure oxygen fluid bed**
JWP Energy Products (EPI)	**USA**	**Fluid bed**
LNETI	Portugal	Fluid bed
Lurgi GmbH	**Germany**	**Circulating fluid bed**
Manzano/Linz	Italy	Updraft
MTCI	**USA**	**Fluid bed**
NEI Fluidyne	New Zealand	Downdraft
Sofresid/Caliqua	**France**	**Updraft**
Southern California Edison	USA	Downdraft
Southern Electric Int.	**USA**	**Fluid bed air**
Steine Industrie (ASCAB)	France	Pressure oxygen fluid bed
Tampella Power	**Finland**	**Pressurized fluid bed**
Thermoselect	**Switzerland**	**Two stage pyrolysis—gasification**
TNEE	France	Twin fluid bed
TPS (Studsvik)	**Sweden**	**Circulating fluid bed**
Tsukishima	**Japan**	**Twin fluid bed**
University of Sherbrooke	Canada	Fluid bed
Veba	Germany	Entrained flow
Ventec	UK	Downdraft
Voest Alpine	Austria	Updraft
Vølund	Denmark	Updraft
VUB	Belgium	Fluid bed
Wellman	**UK**	**Updraft**

[a]Ref. 6. Processes in **bold face** either have been or are being seriously considered for large-scale commercial applications

It can be seen that there are few technology types that are not being exploited. Only the pressurized indirectly heated fluid bed and the atmospheric entrained flow system are not being developed. Finally, *Table 10* lists those processes that are being developed for power generation.

GAS CLEANUP

Gases formed by gasification are contaminated by some or all of the constituents listed in *Table 11*. The level of contamination varies, depending on the gasification process and the feedstock. Gas cleaning must be applied to prevent erosion, corrosion and environmental problems in downstream equipment. *Table 11* also summarizes the main problems resulting from these contaminants, and common cleanup methods.

Hot gas cleanup for particulates

Gas streams from biomass gasification contain very small carbon-containing particles wich are difficult to remove by cyclones. Tests using high-efficiency cyclones[19] showed that particulate levels were not reduced to <5–$30\ g\ m_s^{-3}$, and barrier filtration methods using e.g. sintered metal or ceramic filters are preferred. Hot gas cleanup is particularly important for pressurized systems, where the sensible heat of the gas needs to be retained and scrubbing systems for tar removal avoided.

High-temperature ceramic or metal candle filters have been tested with gasification products from peat and coal.

Table 9 Major gasification activities

Gasifier type	Organization	Current status	Future plans
Bubbling fluid bed			
Atmospheric	JWP, USA	Steam for power	Not known
	SEI, USA	Process heat	Not known
	U. Sherbrooke, Canada	Development	Electricity
	VUB, Belgium	Design	Not known
Pressurized	IGT, USA	Demonstration	Electricity; methanol later
	HTW, Germany, Finland	Co-firing for electricity, ammonia	Electricity, syngas
	Tampella, Finland	Testing	Electricity
Circulating fluid bed			
Atmospheric	Ahlström, Finland	Process heat	None
	Battelle Columbus, USA	Development	Licensing
	Gotaverken, Sweden	Process heat	Not known
	Lurgi, Germany	Process heat	Process heat, electricity
	TPS, Sweden	Process heat; electricity	Electricity
Pressurized	Bioflow, Finland	Demonstration	Electricity
Indirectly heated fluid bed			
Atmospheric	MTCI, USA	Design	Electricity through steam
Fixed bed			
Atmospheric	Bioneer, Finland	Heat	Not known
	Sofresid, France	Heat	Not known
	Volund, Denmark	Development	Electricity
	Wellman, UK	Process heat	Electricity
Pressurized	General Electric, USA	Development	Electricity
Entrained flow			
Pressurized	Veba, Germany	Development	Not known
	Texaco, USA	Co-firing for power	Electricity
Miscellaneous			
Atmospheric	Thermoselect, Switzerland	Demonstration	Waste disposal

Table 10 Gasification-to-electricity systems installed, proposed or planned

Organization	Gasifier	Technology[a]	Generator[b]	Status	MWe
Aerimpianti	TPS	CFB	Steam turbine	Operational	6.7
Bioflow	Ahlström	Pressure CFB	Gas turbine CC	Commissioning	6
Elsam	Tampella	Pressure FB	Gas turbine CC	Design	7
ENEL	Lurgi	CFB	2 gas turbines CC	Design	12
General Electric	GE	Updraft	Not specified	Design	–
GEF	Not decided	Not decided	Gas turbine CC	Evaluation	27
PICHTR	IGT	Pressure O_2 FB	Not specified	Commissioning	2–3
North Powder	JWP (EPI)	FB	Steam turbine	Not known	9
MTCI	MTCI	FB	Gas turbine	Design	4
Vattenfall	Tampella	Pressure FB	Gas turbine	Deferred	60
VUB	VUB	Fluid bed	Gas turbine (Brayton)	Design	0.6
Yorkshire Water	TPS	CFB + cracker	Gas turbine CC	Design	8

[a] FB = fluid bed; CFB = circulating fluid bed
[b] CC = combined-cycle operation

Table 11 Fuel gas contaminants, problems and cleanup processes

Contaminant	Examples	Problems	Cleanup method
Particulates	Ash, char, fluid bed material	Erosion	Filtration, scrubbing
Alkali metals	Sodium and potassium compounds	Hot corrosion	Cooling, condensation, filtration, adsorption
Fuel nitrogen	Mainly NH_3 and HCN	NO_X formation	Scrubbing, SCR[a]
Tars	Refractory aromatics	Clog filters, difficult to burn, deposit internally	Tar cracking Tar removal
Sulfur, chlorine	H_2S, HCl	Corrosion, emissions	Lime or dolomite scrubbing or absorption

[a] Selective catalytic reduction

Many designs do not give a constant pressure drop, the differential increasing as the deposits build up. One solution is to layer the filters and in this case removal efficiencies of >99.8% have been reported. Tests on wood-derived gases have revealed a further problem with filter clogging by soot arising from thermal cracking of tars both in the gas phase and on the filter surface. This problem can be reduced by cooling the gas to <500°C and reducing gas velocities across the filter surface. However, if temperatures fall below 400°C, there remains a potential problem of tar deposition. Recent developments utilize ceramic candle filters with automatic pulsing to strip off the accumulated filter cake.

Tar cracking

Tar concentration is mainly a function of gasification temperature, decreasing as temperature increases. The relation between temperature and tar level is a function of reactor type and processing conditions. The tars formed in pyrolysis are thermally cracked in most environments to refractory tars, soot and gases.

Tar levels and characteristics are also dependent on the feedstock. Tests have shown that tar production in wood gasification is much greater than in coal or peat gasification and that the tars tend to be heavier, more stable aromatics[10]. These may partly react to give soot which can block filters, a problem apparently peculiar to biomass gasification. This implies that technology developed in coal gasification tar cleaning may not be directly transferable to biomass feeds.

There are two basic ways of destroying tars[7]:

- by catalytic cracking using, for example, dolomite or nickel,
- by thermal cracking, for example by partial oxidation or direct thermal contact.

Catalytic cracking. Pilot-scale tests have shown that catalytic cracking of tars can be very effective. Tar conversion of >99% has been achieved using dolomite, nickel-based and other catalysts at elevated temperatures, typically 800–900°C. These tests have been performed using both fossil and renewable feeds. Most reported work used a second reactor. Some work has been carried out on incorporation of the catalyst in the primary reactor, which has often been less successful than use of a second reactor[20], although this approach has been selected for the Biopower plant at Varnamo[6]. Elevated freeboard temperatures thermally crack tars and can reduce the load on the catalytic cracker.

Catalyst deactivation is generally not a problem with dolomite. An initial loss of activity is sometimes experienced as carbon compounds deposit on the catalyst, but these compounds gasify as the bed temperature rises and the catalyst is reactivated. Metal catalysts tend to be more susceptible to contamination. Low hydrogen concentrations in the product gas reduce the catalytic activity of metal-based systems. The low sulfur content of biomass gases can reduce the activity of metal sulfide catalysts through stripping-out of the sulfur.

Thermal cracking. Tests on a fluidized bed peat gasifier have shown that tar levels can be reduced to those found in downdraft systems by thermal cracking at 800–1000°C[10]. However, biomass-derived tars are more refractory and are harder to crack by thermal treatment alone. As indicated above, elevated freeboard temperatures in fluid bed gasifiers provide some thermal tar cracking.

There are several ways of achieving thermal cracking:

(1) By increasing residence time after initial gasification, such as in a fluid bed reactor freeboad, but this is only partially effective.
(2) By direct contact with an independently heated hot surface, which requires a significant energy supply and thus reduces the overall efficiency. This is also only partly effective, owing to reliance on good mixing.
(3) By partial oxidation by addition of air or oxygen[8]. This increases CO_2 levels, reduces efficiency and increases costs for oxygen use. It can be very effective, particularly at the high temperatures of $\geqslant$1300°C achieved with oxygen gasification.

Tar removal

Water scrubbing is widely assumed to be a proven technique for physical removal of particulates, tars and other contaminants. Unfortunately, most experience is not so reassuring and there are many reported problems, particularly in the poor efficiencies of tar removal, although surprisingly few hard data are available[21]. Tars require physical capture and agglomeration or coalescence more than simple cooling; biomass-derived tars are known to be very difficult to coalesce, and a complex treatment system is likely to be required even to attain 90% tar removal.

A typical system includes a saturator to cool and saturate the gas for coalescence of particulates and tars in the next stage. A high-efficiency scrubber then follows to contact the contaminants intimately and reduce the pressure so that the water will condense on to the particulates and tar droplets, thus increasing their size and improving their susceptibility to agglomeration and coalescence. A final stage provides a high-residence-time tower to allow the system to equilibrate. Tar levels down to 20–40 mg m_s^{-3} and particulate levels down to 10–20 mg m_s^{-3} can be achieved with such a system. Soluble gases such as ammonia and soluble solids such as sodium carbonate are effectively removed. These systems are fairly expensive and create a waste disposal problem by generating large quantities of contaminated water. This can usually be treated by conventional biological processes unless there is a high recycle ratio, when more concentrated solutions will be produced, requiring special disposal. Cooling of the product will also reduce electrical efficiency, but is essential for applications in engines to provide gas of the highest energy density.

A few attempts have been made to scrub with oil, thought more likely to capture the tars, but the consequent problems outweighed any benefits. Electrostatic precipitation is an effective but costly way of removing tars, but there is little experience on biomass-derived gasification products.

Alkali metal compounds

Alkali metal compounds exist in the vapour phase at high temperatures and therefore pass through particulate

removal devices unless the gas is cooled. The maximum temperature that is considered to be effective for condensing metal species is ~600°C. Tests on alkali species have shown that their gaseous concentrations fall with temperature to the extent that concentations are close to turbine specifications at temperatures <500–600°C[10]. Thus it is possible that gas cooling to this level will cause alkali metals to condense on to entrained solids and be removed at the particulate removal stage. Alkali metals may also damage ceramic filters at high temperatures, and a cleanup system will thus need a cooler before the hot gas filter. Alkali metals cause high-temperature corrosion of turbine blades, stripping off their protective oxide layer, and for this reason it is widely believed that the alkali concentration must not exceed 0.1 ppm at entry to the turbine. There is no experience with modern coated blades in such an environment. Alternatively, or additionally, water scrubbing can be used, as described above.

Fuel-bound nitrogen

50–80% of fuel-bound nitrogen is converted to ammonia and smaller quantities of other gaseous nitrogen compounds such as hydrogen cyanide during gasification. These compounds will cause potential emissions problems by forming NO_x during combustion. Nitrogen-containing contaminants all exist in the vapour phase and will therefore pass through all particulate removal devices. There are four ways of approaching the problem of NO_x emissions, any of which may be used singly or in combination:

(1) Reduction of the formation of NO_x by limiting fuel-bound nitrogen in the feedstock through careful selection of biomass types and/or blending.
(2) Wet scrubbing, which removes ammonia and other soluble nitrogen compounds, but results in loss of sensible heat and thus poorer efficiencies.
(3) Use of low-NO_x combustion techniques to minimize thermal NO_x production.
(4) Use of selective catalytic reduction (SCR) at the exhaust of the engine or turbine. SCR involves a reaction between ammonia and NO_x to form nitrogen and water. This is well-established technology and is often specified for exhaust gases from engines and turbines. However, there is a capital cost and an efficiency penalty of 2–4%.

Sulfur

Sulfur is not generally considered to be a problem, since biomass feeds have very low sulfur contents. However, the specification for turbines is typically 1 ppm or often much less, and lower still if co-contaminants are present, such as alkali metals. Some gas compositions have been reported with 0.01 vol.% S (100 ppm). Sulfur removal may therefore be necessary for turbine applications and can often be achieved with a conventional sulfur guard. Sulfur concentrations are lower than those produced in the combustion of fossil fuels, and hence expensive sulfur removal trains are not necessary. If a dolomite (CaO.MgO) tar cracker is included in the process, this will absorb significant proportions of sulfur and reduce the levels considerably, but possibly not to the low levels required. A sulfur guard, consisting of a hot fixed bed of zinc oxide, is likely to be adequate for the concentrations expected. This would be relatively inexpensive to install but would create a waste disposal problem from the zinc sulfide produced.

Chlorine

Chlorine is another potential contaminant, which can arise from pesticides and herbicides as well as in waste materials. A level of 1 ppm is often quoted, but this is a function of the temperature, chlorine species, co-contaminants, and materials of construction. The behaviour of chlorine and metals at elevated temperatures is well understood. Chlorine and its compounds can be removed by absorption in active material either in the gasifier or in a secondary reactor, or by dissolution in a wet scrubbing system. Dolomite and related materials are less effective at removing chlorine than sulfur.

POWER GENERATION INTERFACING REQUIREMENTS

Definition

The product gases from gasification of biomass may be used in either gas turbines or engines for the generation of electricity. This section considers gas quality requirements and control techniques that are required to make the use of gas turbines or engines a feasible proposition. The gas quality requirement for a gas turbine is known to be very demanding, in that only extremely low levels of any solid or liquid contaminant, and of some gaseous contaminants such as sulfur and chlorine compounds, can be tolerated, but there are no specifications available for design of gas cleaning systems. A common response to a question on tolerance levels for any contaminant is either 'zero' or 'the same as natural gas'. Results from ongoing and planned large-scale tests will provide better data.

The problem is one of optimization. Increasingly stringent gas cleaning systems will cost more but will increase the life of the turbine and/or reduce the maintenance costs. Conversely, relatively poor gas cleanup will cost less but reduce the turbine life and/or increase maintenance costs. There will be an economic optimum combination of gas cleanup and turbine costs, but this cannot yet be specified.

Gas quality requirements

Turbine operation. Some typical conventionally stated turbine fuel gas specifications are summarized in *Table 12*. It must be emphasized that this list indicates some of the known problem areas; the specifications are not definitive but serve to show the extent to which the fuel gas may have to be cleaned according to various sources. Indeed, some of the specifications may need to be much more strict, with some contaminants possibly reduced to one-tenth of the stated values, particularly in difficult combinations.

Known major problems are posed by alkali metals and sulfur. Sulfur is not normally associated with biomass, but what are often viewed or claimed as 'trace' levels of, for example, 0.1 wt%, can lead to levels of sulfur in the fuel gas of up to 100 ppm. This level is not acceptable (see *Tables 11* and *12*) and will require reduction. Alkali metals are a major component of the ash of many biomass forms and their effect on turbines is well known, although

Table 12 Some notional gas turbine fuel specifications

Minimum gas heating value (LHV) (MJ m_s^{-3})	4–6
Minimum gas hydrogen content (vol. %)	10–20
Maximum alkali concentration (ppb)	20–1000
Maximum delivery temperature (°C)	450–600
Tars at delivery temperature	All in vapour form or none
NH_3	No limit
HCl (ppm)	<0.5
S (H_2S+SO_2 etc.) (ppm)	<1
N_2	No limit
Combinations: total metals (ppm)	<1
alkali metals + sulfur (ppm)	<0.1
Maximum particulates (ash, char etc.) (ppmw)	
at particle size (μm) of >20	<0.1
10–20	<1.0
4–10	<10.0

the particular nature of the biomass-derived alkali metals and their association with other contaminants such as sulfur is not known.

Solid inerts such as char and fluid bed material will clearly have a deleterious effect on any moving parts and will require almost total removal. Suggested limits are indicated in *Table 12.*

Tars are a potential problem if the gas has to be compressed, as with an atmospheric gasifier, since they will deposit in the compressor. Pressurized gasifiers overcome this problem by removing the need for a fuel gas compressor, as the gas can be filtered hot and burned hot with the tars remaining in the gas phase and combusted. Tars otherwise will require cracking and/or removal, as discussed below.

Chlorine is a difficult contaminant, as it interacts with most metals at gasification and combustion temperatures. Changing from a reducing (as in the gasifier) to an oxidizing environment (as in the combustor) exacerbates the potential problem. The reactions between chlorine and most metals are well known and the operating regimes well understood.

Biomass often contains nitrogen, particularly from bark and some special biomass forms. NO_x generated from fuel-bound nitrogen may cause problems, and gas cleaning should therefore reduce traces of HCN and NH_3 to a minimum. This is adequately dealt with in a water scrubbing system, but in a pressurized system, with hot gas filtration, a post-combustion catalytic process (SCR) would be required.

There will be a trade-off between increasing the gas cleaning to a high standard and increasing the maintenance cost of the turbine. This interaction has not been studied and no data are available.

Engine operation. Engines have the advantage of higher tolerance to contaminants than turbines (e.g. up to 30 ppm tars can be tolerated). If the gas is compressed in a turbocharger there will be similar but possibly less demanding quality requirements on the gas. There are no firm or reliable data on the gas quality specifications required.

Control requirements

If the gasifier operates at atmospheric pressure, the product gas will require compression before combustion, as well as the air. This imposes severe gas quality requirements to avoid damage to the compressor. The air supply to the gasifier would probably be provided independently, although a bleed from the air compression loop could be used. However, this latter choice would require extensive compressor modifications and impose severe control problems on the system, analogous to those for a pressure gasifier. A pressurized gasifier would either use compressed air from the compressed air loop on the turbine set or would have an independent air compressor. The latter solves some of the potential control problems that arise from integration of the gasifier operation with the turbine, but at the expense of higher cost and lower system efficiency.

Engines present a more tolerant control requirement through the use of conventional fuel mixing devices and orthodox engine management systems. They will tend to react positively and quickly to variations in gasifier output without adversely affecting the gasifier operation. There is extensive practical experience of such systems from small-scale gasifier operations as well as landfill gas operations.

POWER GENERATION

Definition

The principle of power generation from a gas turbine is well known. Air at ambient temperature and pressure is compressed in order to burn the compressed fuel gas. The hot exhaust is passed through a gas turbine, where some of the heat energy is recovered as work and the rest is discharged as waste heat. Some of the work is used to compress the air and the remainder is used to generate electricity.

This simple cycle is not very efficient, since there is considerable energy wasted in the hot exhaust gases. Efficiency can therefore be increased by adding a heat recovery system after the gas turbine. These systems can either generate steam or preheat the air. The steam can power a steam turbine in a combined-cycle mode, or it can be added to the turbine combustion chamber or mixed with the combustion gases and fed through the gas turbine in a steam-injected gas turbine (STIG) cycle. Owing to the low heating value of the fuel gas there is a practical limit to the extent to which steam can be added to the combustion chamber without extinguishing the combustion. System optimization is very complex; work is under way in the IEA Bioenergy Agreement to model and optimize such a system. The residual heat from the steam turbine or air preheater can be used for process steam or for district heating, or may be used in the process, for example for wood drying.

Gas turbines are proven in power generation when fuelled by high-grade fossil fuels such as natural gas or liquid fuels such as diesel. Fuels of low heating value such as gases produced by biomass gasification have not been demonstrated in gas turbines, although gas of medium heating value from coal gasification has been used successfully, for example at the Cool Water demonstration coal integrated gasifier–combined-cycle (CIG–CC) 100 MWe facility in the USA[22].

Biomass gasification-to-electricity system: special requirements

The special requirement of a biomass-based system is that if the gasifier operates at atmospheric pressure the product gas will require compression as well as the air. The air supply to the gasifier would probably be provided independently, although a bleed from the air compression loop could be used. This latter choice would require extensive compressor modifications and impose control problems on the system. Thus a separate additional compressor is required.

A pressurized gasifier would either use compressed air from the compressed air loop on the turbine set, or have an independent air compressor which would solve some of the potential control problems described above, but at the expense of higher cost and lower efficiency.

Combined-cycle operation will utilize not only the waste heat from the exhaust but also heat recovered from the primary gas cooler before filtration. System optimization is thus a major requirement and requires careful consideration. The problem is exacerbated if a STIG is used or if the gasifier requires steam.

Fuel specifications and turbine/engine requirements

Coal integrated gasification (CIG) capacities are far greater than the capacities proposed for biomass systems, typically ranging from 100 MWe at a demonstration scale to 1000 MWe. The gas turbines used are bigger and more tolerant of gas contamination. Biomass-based systems are limited in size by the availability and collection costs of the resource. There are few advocates of biomass-based combined-cycle power systems above 50–100 MWe, and few sites where biomass can be delivered in sufficient quantities: 40 t h^{-1} (daf) at 45% efficiency for 100 MWe. Contaminant limits for systems based on biomass integrated gasification (BIG) will have to be much stricter to ensure a long turbine life, as suggested in *Table 12*, although definitive limits have yet to be finalized.

Fuel combustion

The heating value of gaseous fuels from biomass gasification is only 10–50% of that of natural gas (see *Table 7*). This means that a correspondingly greater volume of fuel will have to be burned to supply an equivalent amount of heat. Combustion chambers and burners will require modification to cope with the higher throughput as well as to meet increasingly stringent environmental requirements. Contaminant limits may have to be tightened to account for the extra volume of fuel gas required.

A low flame temperature is expected from combustion of gas of low heating value, owing to dilution by nitrogen. This will reduce thermal NO_x production, which is therefore not expected to be an environmental problem. The composition of gases of medium heating value, which are largely hydrogen and carbon monoxide with some methane, suggests that they will have a high flame temperature, which could lead to NO_x problems. Burners for such gases will have to be carefully designed to account for this, or some form of dilution may be necessary, possibly by the nitrogen extracted in oxygen gasification, or by steam. SCR processes are available for reducing NO_x in exhaust gas, but there is an economic and energetic penalty. Any fuel-bound nitrogen, such as from bark in particular, will require gas cleaning or a selective catalytic reduction process as described above.

It would be desirable for the turbine to have a dual-fuel capability to supplement fuel gas and to ensure maximum availability. However, this will almost certainly require a new burner design, and also additional modifications to the combustion chambers.

One way of avoiding the problems of gas cleaning is to burn the fuel in a separate combustor and heat the turbine gases indirectly in a high-temperature gas–gas heat exchanger (a Brayton cycle). This approach is applied at the Free University of Brussels (VUB) CHP plant[23]. The main problem is the loss of efficiency caused by indirect heating of the turbine working gases, and the temperature limit imposed by the heat exchanger materials, which limits the efficiency attainable. Although indirect heating improves turbine reliability, there are costs incurred in flue gas treatment and the gas–gas heat exchanger.

Energy recovery

Combined cycle. Exhaust gases typically leave the gas turbine at 500–600°C for aero turbines and 400–500°C for industrial turbines, and so still have considerable thermal energy. This energy, and that of other high-temperature gas sources such as the raw gas from the gasifier, can be recovered in a heat-recovery steam generator (HRSG). This steam can be used in a steam turbine to generate extra electricity. The steam is then cooled and condensed in a cycle before passing once again through the generator. This combination of gas turbine and steam cycle is known as a combined cycle (CC). The waste heat from the steam turbine can be recovered as heat, for example for district heating.

Steam turbines and boilers are normally only economic in large-scale applications (> 100 MWe), unless there are special circumstances such as low-cost feedstocks, and for this reason combined cycles are very sensitive to scale. Steam-injection gas turbine (STIG) cycles may be more appropriate to smaller generating systems, but there is no experience of such a system applied to biomass-derived gases.

Steam injection cycle. In steam-injection cycles, the HRSG raises steam which is then mixed with the compressed air in the gas turbine cycle. Steam is injected at the combustion chamber and at points before entry to the gas turbine. This increases the gas turbine throughput and hence the power output. The exhaust gas stream requires a flue gas condenser. This system is commercially available in natural-gas-fired aero gas turbines, although there is no experience with gases of low heating value. In such duties the steam may dilute the fuel to the point where combustion is unstable. There is also the possibility that turbine capacity may be exceeded. This system uses the exhausted waste heat effectively, without the need for large boilers or a steam turbine, which makes it insensitive to scale. It is favoured because it is claimed to be the most economic option in small-scale facilities. However, there is a problem in ensuring an adequate water supply.

Evaporative cycles are similar to STIG except that water is injected instead of steam. This is vaporized in the gas–gas heat exchanger. Performance is reported to

be better than STIG or combined cycles, but the cycles are less established.

Combined heat and power (CHP). In all the cycles noted, excess heat or steam can be used as process steam or in district heating. This will increase overall system efficiency, but with additional capital cost.

Status

There are two basic machines for generating power: turbines and engines. There is no clear allocation of choice of machine and size of system, but the orthodox view is that engines are more suitable up to 5–10 MWe, and turbines above 10–20 MWe for an atmospheric pressure gasifier and above 20–30 MWe for a pressure gasifier. Engine gen-sets are, however, available up to 50 MWe, and gas turbines have been successfully used on low-quality gas at 3 MWe. The pros and cons of turbine options are listed in *Table 13*. Turbines become more attractive at larger sizes, particularly for IGCC and similarly advanced cycles, when higher efficiencies can be achieved and economies of scale become more noticeable.

Engines have the advantages of robustness, high efficiency at small sizes, higher tolerance to contaminants than turbines (e.g. up to 30 ppm tars), easier maintenance, and wide acceptability. However, operation in combined-cycle mode is rarely justified, as only a small increment in efficiency can be gained. There is poor economy of scale, as capacity is a function more of number of cylinders than of their size, and constant specific capital costs that are independent of size are typical.

Table 13 Turbine options

Industrial	Lower efficiency
	More tolerant to contaminants
	Higher cost
	Higher availability
	Higher maintenance costs
Aero	Higher efficiency
	Less tolerant to contaminants
	Lower cost
	Lower availability
	Lower maintenance costs

ENVIRONMENT

The operation of a gasification plant can result in occupational health and safety hazards unless adequate and effective preventive measures are taken and continuously enforced.

A gasification system comprises:

- fuel storage, handling and feeding system,
- the gasifier, gas cooling and cleaning equipment,
- utilization of the gas.

Each part of the plant creates specific occupational, health and safety hazards. *Table 14* describes the main environmental concerns and major hazards associated with the operation of gasification system. This section examines the sources of environmental concerns and describes the measures which have to be taken to limit environmental impact; it considers only in-plant environmental factors concerning gas, liquid and solid emissions and wastes. The major hazards are then discussed and safety guidelines are provided for appropriate operation of gasifier systems. Although there is probably nothing unusual in the problems and plant requirements, an overview of these will be helpful in plant specification and evaluation.

Environmental aspects of gasification operations

Dust. Dust is generated during preparation, storage and handling of the feedstock, feeding, and fly ash removal by particulate collection equipment; all of these present particular problems when the solids are dry and friable. Dust generation creates several possible problems, including:

- formation of explosive mixtures with air (a primary explosion can render the dust airborne, causing secondary explosions which can be devastating);
- inhalation causing lung damage;
- eye and skin irritation;
- smells from, or smouldering and ignition of, layers of combustible dust;
- dust settlement on all exposed horizontal surfaces, leading to safety problems for personnel in routine operations, as well as increased maintenance and aesthetic detraction;

Table 14 Environmental aspects of gasification systems

Process activity	Fuel preparation	Feeding system	Gasifier	Gas cleaning	Gas utilization
Environmental concerns					
Dust	*	*		*	
Noise	*	*	*	*	*
Odour	*		*	*	
Wastewater				*	*
Tar				*	*
Fly ash				*	
Exhaust gases					*
Hazards					
Fire	*	*	*	*	*
Dust explosion	*	*	*		
Mechanical hazard	*	*	*		*
Gas poisoning		*	*	*	*
Skin burns			*	*	*
Gas explosion			*	*	*
Gas leaks			*	*	*

- increased friction and wear of mechanical equipment caused by dust deposition, increasing costs and reducing reliability, both increasing the potential for accidents.

Preventive measures include:

- minimization of solids handling and avoidance of rough handling to minimize attrition of fuel particles and suspension of dust;
- complete enclosure of all solids-handling, particularly conveying equipment at the discharge points;
- installation of suction hoods and gas cleaning equipment to control localized dust sources, for example mills and screens;
- maintenance of an underpressure in enclosed environments to prevent the spreading of dust into adjacent premises, again with suitable gas cleaning equipment.

Solid particles also arise in the product gas, such as cinders, fly ash, filter dust, charcoal, fluid bed inerts and catalyst fines. Since such sources are localized, they are in principle easier to control. Fine materials such as fly ash may need to be wetted to prevent re-entrainment during handling and disposal. Carbon formed by secondary cracking or incomplete gasification can also form explosive mixtures with air, but it is usually contained in appropriate vessels. Charcoal from biomass can be pyrophoric and needs to be adequately cooled before discharge and storage if arising in significant amounts. Some types of gasifiers may produce hot particles, as a consequence of malfunction or equipment faults, which may ignite flammable materials and cause a fire.

From an occupational health viewpoint, dust particles may be classified by:

(1) *Size*: particles $>5\,\mu m$ are arrested by wet hairs in the nostrils. Those $<0.2\,\mu m$ do not settle in the lungs and are breathed out again. Hence the intermediate size range is the most dangerous.
(2) *Shape and composition*: some materials are known to cause lung damage, for example asbestos (asbestosis) and silica (fibrilosis). The latter may arise from fluid bed materials.

Dust originating from fly-ash removal may be toxic owing to adsorption of chemicals on to the dust particles. Several compounds with carcinogenic properties, such as benz[*a*]anthracene and benzo[*a*]pyrene are adsorbed on to the dust particles. They are dangerous to human health after inhalation and skin contact and/or after accumulation in the food chain. Dust particles may adsorb non-polar organic compounds up to 40% of their weight, possibly higher for soot and carbon black with their very high specific surface areas. The dispersion of gasifier dust may lead to air and food contamination.

Wastewater and condensables. The present trend is to produce a clean tar- and ash-free gas that may be directly burned in an engine or turbine, and there is a positive effort to design and develop systems that do not produce a liquid effluent, because of the potential problems of treatment and disposal. However, if wastewaters and condensates are produced during gas cooling and wet gas cleaning, they will require treatment[13]. The condensate is known to contain, for example, acetic acid, phenols and many other oxygenated organic compounds that may be soluble or insoluble in water. There is a risk of water pollution and adverse health effects from the suspended tars and soluble organics. The condensate and wastewaters consist mainly of water, and can be divided into an aqueous, i.e. water-soluble fraction, and a non-water-soluble fraction consisting of tars and oils. However, separation is not always simple, since wood tar tends to emulsify in the aqueous phase. The insoluble fraction consists mainly of ash and particulates, tars, phenolic compounds and light oils.

The tars in particular, as well as the condensates, are toxic and require careful evaluation of their occupational and safety aspects. Little research hs been carried out to determine the mutagenic and carcinogenic effects of biomass tar, but research on coal tar has confirmed the above reservations. It would be prudent to assume that some of the tar components may be carcinogenic. High-temperature gasifier operations can increase this problem, since the mutagenic and carcinogenic effects are related to the presence of polycyclic aromatics and their relative concentrations increase as process temperature increases. Direct content between skin and tars or condensates should be avoided by appropriate clothing and training.

Tars present an insignificant fire hazard, as their flash points are comparatively high. Tar disposal has not been examined, but it is usually assumed that it may be recycled to the gasifier or incinerated. Other disposal options are unlikely to be acceptable. No work is known to have been carried out on other uses for the tar, such as chemicals recovery and direct applications such as road tar, although chemicals from biomass via flash pyrolysis are of major interest[7]. There are too few substantial biomass gasification plants currently operating from which tars could be recovered, and all of the current interest is focused on production of clean gas through tar cracking rather than on removal and recovery.

Since tars are such a potential problem in wastewaters and in their own right, every effort should be made to reduce their environmental impact by:

- cracking tars during or after gasification,
- applying hot gas cleanup and so avoiding wet gas scrubbing,
- reducing gasification temperatures to limit the production of refractory polycyclic tars.

Pressurized gasifiers are assumed to operate with hot gas cleanup, no wastewater and no tar production. Atmospheric pressure gasifiers are more likely to include a wet scrubbing system, particularly if an engine is specified for power generation.

Wastewater treatment is usually assumed to be relatively simple and low-cost, although there is remarkably little information on treatment methods or costs[13]. The design of the wastewater treatment plant would be expected to rely partly on chemical treatment, such as solvent extraction for high concentrations of phenolics, with incineration of recovered organics, and orthodox biological treatment of the dilute, low-BOD effluent. Although tar separation and recycling to the gasifier for thermal destruction have been proposed, no examples of application have been found.

Fly ash and char. Fly ash and char present similar problems to those caused by dust as described above. There is an additional risk of fire, which dictates that fly ash and char should be stored moist. Disposal of this wetted mixture presents its own environmental problems. The solids need to be separated from the water in a water treatment facility. Extracted water will be contaminated and may require further treatment before discharge, using orthodox water treatment technology. There are no known special problems. The solid fraction should be considered an industrial waste and discharged accordingly to licensed landfill sites.

Odour problems. Odours may arise because of:

- the degradation of organic matter (for example in refuse or sewage gasification),
- the occurrence of even minute gas leaks,
- the handling and storage of tar, wastewater, fly ash and other by-products.

Wood tar has a strong, characteristic and persistent odour, even in minute concentrations. The smell of coal tar is somewhat aromatic owing to the presence of naphthalene, anthracene and phenanthrene. Tar derived from lignocellulosic feedstocks is more pungent.

When sulfur- or nitrogen-containing feedstocks are used, the producer gas also contains odorous gases, such as H_2S, COS or NH_3. The tar and wastewater may be contaminated by even more strongly smelling organic sulfur and nitrogen compounds, although this is unlikely to be a problem with biomass-derived products, owing to the very low levels of sulfur and nitrogen. Some waste materials such as sewage sludge may cause such problems.

Noise. Noise is produced whenever a mechanical part or an engine or motor is in operation. Particular plant areas where noise levels are likely to be significant are:

- reception, storage and handling equipment,
- the feeding system,
- the compressors,
- the gas turbine or engine.

The effects on humans of prolonged exposure to noise are well documented. Adequate measures must be taken to minimize noise, for example by using sound- and vibration-absorbant materials between supports or acoustic enclosure. Operators are also required to be provided with ear protection plugs.

Hazards of gasifier operation

Combustible gases and vapours. A flammable gas is combustible only within a certain range of concentrations, bounded by the LEL (lower explosion limit) and the UEL (upper explosion limit). Below the LEL, the mixture is too lean to sustain combustion. Above the UEL the reaction stops because of a deficiency in oxygen. In both cases the generation of heat becomes too slow to give rise to the characteristic acceleration in reaction rates which marks the start of an explosion. The range between the LEL and UEL values depends on the reactivity of the flammable compound or mixture. It widens when the flammable gas or the combustion air is preheated or under pressure. Some data are given in *Table 15*.

Explosive mixtures could arise in two situations:

(1) Air leaks into the gasifier plant as a consequence of a reduction in operating pressure. Reduced pressure may arise due to rapid cooling, condensation of vapour such as water, chimney effects, or the suction of an induced-draft fan or of an engine.
(2) Fuel gas leaks out of the gasifier plant into a confined space, thus building up a substantial concentration in an enclosed space. A source of ignition is necessary for an explosion, so explosion-proof, flameproof or sparkproof motors would be specified in any such areas. In addition, such an atmosphere is likely to present a lethal toxicity hazard from carbon monoxide, so suitable detectors should be fitted.

When a flammable mixture of gas and air is formed, an explosion may occur if the mixture is ignited. Ignition may occur as a result of static electricity, sparking equipment such as motors, or contact with a hot surface. In view of the wide explosion limits of the main components of producer gas — hydrogen and carbon monoxide — the accidental formation of explosive gas mixtures should be prevented. Mixtures of producer gas with oxygen-enriched air or pure oxygen have a higher UEL than do mixtures with air. The LEL does not change significantly. This means that oxygen gasifiers present an even higher explosion risk, such as when oxygen breaks through the fuel layer or there is a perturbation in the fuel supply.

Combustible dusts. Combustible solids such as wood, flour and coal in very small particles can also form explosive mixtures with air within certain concentration limits, usually ranging from 20 to 50 $mg\,m^{-3}$ for LEL and 2 to 6 $g\,m^{-3}$ for UEL. Numerous carbohydrate materials, including starch, sugar and wood flour, have given rise to extremely destructive explosions.

Fire risks. The main fire risks in gasifier systems are associated with:

- fuel storage,
- combustible dusts formed in fuel comminution,
- fuel drying (in forced-draft conditions a fire is likely to expand quickly),
- ignition procedure (especially for moving-bed gasifiers),
- the product gas.

There are also the usual risks associated with any construction involving a thermal unit. Local rules and guidelines should be followed for construction and materials of buildings. Adequate means for fire-fighting

Table 15 Some LEL and UEL values and self-ignition temperatures in air

	LEL (vol.%)	UEL (vol.%)	Self-ignition temperature (°C)
Hydrogen	4.0	76	400
Carbon monoxide	12.5	74	[a]
Methane	4.6	14.2	540
Ethane	3.0	12.5	515
Ethene	3.1	32.0	490
Propane	2.2	9.5	450

[a] The value is highly dependent on the presence of traces of moisture

should be provided and the gasifier operators should be well acquainted with their existence, location and operating instructions. Such fires can be avoided by proper procedures and proper layout of the plant.

Carbon monoxide poisoning. Carbon monoxide is a major constituent of producer gas and is by far the most common cause of gas poisoning. It is particularly insidious owing to its lack of colour or smell. The accepted threshold limit value (TLV) is 50 ppm CO (0.005 vol.%), although concentration and exposure are closely linked. There is extensive documentation available on effects, treatment and controls laid down by the relevant statutory authorities.

Since carbon monoxide is an odourless, colourless gas, it may be detected only through instrumentation, and personal detectors are necessary when working in confined spaces. All operating personnel should be aware of the hazards presented by the gas. The best way of avoiding the risk of carbon monoxide poisoning is to build the gas generator in the open with the minimum of containment and with adequate ventilation, particularly where gases may collect.

Other toxic compounds. It is well established that extremely toxic dioxins and furans (PCDDs and PCDFs) are formed during most combustion and gasification processes when some chlorine is present. Under normal operating conditions the concentrations of these compounds in wood-fired units are extremely small, although pesticide-treated wood and waste materials can provide the source of chloride necessary for their formation. A close-coupled IGCC system normally provides satisfactory operating conditions for thermal destruction of these compounds and it is generally believed that they do not present any problem, though very few data exist to support this.

Other hazards. Other hazards include skin burns, mechanical hazards and electrical hazards. Some of the surfaces of the gasifier, the cyclones, the gas lines, the engine and its exhaust may get sufficiently hot during operation to create the hazard of skin burns. For permanent stationary installations such surfaces should be insulated to protect the operators and also to reduce heat losses. Covers or rails should be installed to keep personnel at a safe distance. All equipment with moving parts such as blowers, fans, screw conveyors, front-end loaders and pretreatment and feeding equipment present a hazard from moving parts and should be suitably protected. All electric appliances provide the potential for electric shocks, and suitable precautions need to be taken, using standard procedures and equipment specifications.

Any work on elevated equipment involves the hazard of possible falls. Similarly there is some hazard from falling objects, tripping on hot equipment or slipping on oil-stained floors. Unauthorized, inexperienced or untrained personnel should be prevented from entering the plant, to reduce the risk of injury through improper use of equipment or facilities. For all 'normal' hazards that may arise in a process plant there are well-documented and statutory requirements.

Conclusions

The gasification system has to be designed to meet all local environmental and safety requirements. If it is operated correctly and no accidents occur, then the environmental impact will normally be acceptable. Safety design is a major consideration and there is a range of precautions that have to be included and provided for, which will be defined internationally, nationally and locally. In addition, an important aspect of safety and environmental management is good training. The general factors are outlined above but there may be additional specific requirements in respect of the following:

- dust from feed handling,
- dust explosions,
- gas explosions,
- carbon monoxide poisoning,
- tars and wastewater management,
- solids disposal,
- noise.

All of these factors can be adequately managed through good design and operating practice.

STATUS AND TECHNICAL UNCERTAINTIES

Typical system

Table 16 shows typical IGCC systems for both atmospheric and pressure systems from plant gate to grid by identifying each operation in the process and specifying typical equipment. Each of the main areas is described below, with particular reference to the state of the art and uncertainties.

Pretreatment

The pretreatment steps are relatively well established, with a high level of reliability from experience gained in the pulp and paper industry. The lower quality specifications for a fuel product rather than paper feed permit a less demanding design which helps to minimize capital cost.

Wood as forestry waste or short-rotation coppice would normally be delivered in bulk as whole-tree chips. Wood waste, if acceptable as a feedstock, might be delivered in plank form, requiring comminution. There are no perceived problems in handling or storing wood. This is common practice in pulp and paper mills throughout the world and in smaller biomass combustion systems that operate in many countries.

The drying requirement depends on the gasifier feed specification. Wet wood at typically 50 wt% moisture (wet basis) is generally considered too wet, giving rise to a much dirtier gas, condensation problems and lower efficiencies. Drying to 15–25% is considered acceptable in energy and cost terms. Drying may be carried out in the field and in the storage pile, but this is slow and unreliable, allows loss of material by biological degradation and can cause fires. Rotary kilns are widely specified as dryers, using waste heat and/or combustion of biomass feed, perhaps as screenings or fines, again depending on the gasifier feed specification. Fluid bed, silo and steam dryers have all been used successfully for biomass. None is very efficient, however, and the energy and economic costs are high, but these are outweighed by the lower downstream gas cleaning requirements for

Table 16 Typical IGCC system specification

Operation	Equipment	Specification
Pretreatment		
Weigh	Scales ×2	Daylight hours only, 10 h day^{-1}
Tip	Tipper ×2	
Store	Daybin ×2	Lorry load
Transport	Front end loader	
Store	Radial stacker	2 weeks storage
Reclaim	Front end loader	
Store	Bunker	4 h
Transport	Screw	
Magnet	Overband magnet	Ferrous metal removal
Transport	Conveyor	
Dry	Rotary dryer	To 30% moisture. Other possibilities
Fines recovery	Cyclone	Optional according to gasifier
Fines store	Bin	Optional
Fines transport	Conveyor	Optional. Can be used in dryer
Transport	Conveyor	
Store	Surge bin	4 h. Needed only if drying used
Screen		Optional to separate oversize
Oversize transport	Conveyor	Optional
Oversize comminution	Rechip at 20% capacity	Optional
Transport	Conveyor	Optional
Store	Surge bin	4 h
Transport	Screw to feeder	Needed only if drying used
Gasification		
Atmospheric		
Air blower		
Pressure		
Air compressor		From generator shaft
Air preheater		Optional
Feeder		Significant for pressure system
Gasifier		Range of possible configurations
Cyclone		
Ash transport	Conveyor	
Ash store	Pit	
Ash transport	Conveyor	
Heat recovery	Heat exchanger	Optional steam for combined cycle
Gas cleanup		
Atmospheric		
Tar cracking	Thermal or catalytic	Optional, depends on specification
Hot gas filter	Ceramic or metal	
Heat recovery	Heat exchanger	
Saturator	Packed column	
Scrubbing	Venturi or column	
Water treatment		Depends on process specification
Pressure		
Tar cracking	Thermal or catalytic	Optional, depends on specification
Hot gas filter	Ceramic or metal	
Heat recovery	Heat exchanger	
Power generation		
Gas turbine		
Heat recovery		
Steam turbine		
Electrical connection		

dried feed. The operation is well established and extensive experience is available.

Different gasifiers have different feed requirements. Fluid and circulating fluid beds are the most tolerant of particle size range, while fixed-bed gasifiers require regularly sized and relatively large particles with a minimum of fines. Entrained flow gasifiers require a smaller particle size, which can increase technical and economic problems owing to the difficulty in comminuting or grinding wood to small sizes. Comminution and screening are well-established operations in the pulp and paper industry and there are minimal uncertainties.

A typical feedstock specification for a fluid bed or circulating fluid bed gasifier is given in *Table 17*. Gasifier type and system optimization impose more specific requirements.

Gasification

Biomass gasification has been practised for over 100 years, but with little commercial impact, owing to competition from other fuel sources and other energy forms. In the last 20 years, there has been a renewed interest world-wide, with many instances of substantial

Table 17 Typical wood feed specifications

Production method	Chipping, hogging
Size (mm)	
Mean	30
Maxim	50
Minimum	2[b]
Water content (wt%)	25±3
Type of wood	SRF[a] eucalyptus

[a]Short-rotation forestry
[b]<10 wt% below this size

demonstration and commercial-scale plants. In particular, the last few years have seen a major resurgence of interest in large-scale biomass gasification processes, mostly as a result of environmental and political pressures to mitigate CO_2 emissions. Although the technology has progressed steadily over the last 25 years, very few processes have proved economically viable mainly because of the relatively high cost of biomass fuels and lack of a biomass supply chain, as discussed earlier. There are sufficient expertise and knowledge now available for a very high level of confidence to be placed in modern gasification processes. The comments below refer to potential problem areas where concerns have been expressed or to which special attention should be directed.

Recent environmental concerns have created interest in major organizations who have the resources to develop and market suitable technologies that meet environmental and political requirements. The result has been consolidation of interest at an industrial level and substantial speculative investment in these technologies of the future.

Feeding. Biomass has a number of peculiar properties, which relate to its grain structure, that must be considered in designing feeding systems. In devising handling and feeding systems where gas-tight seals are required, provision must be made for particles to fall away or be swept aside, since blockage will result in major physical deformation. This is well known but poorly understood. Pressurized gasifiers are a special and extreme example of this problem, where the feeding system can cost more than the gasifier.

Another problem, particularly with pressure gasifiers, is the inert gas requirement, which can be considerable for purging feeders, owing to the high voidage of most bulk biomass. A commercial plant might consider recycling carbon dioxide from gas combustion, for example, rather than purchasing inert gas in bulk.

Gasification. Recent large-scale demonstration and commercial biomass gasification plants have focused on fluid beds and circulating fluid beds (CFB) rather than fixed beds[6]. This is due to a variety of reasons including scalability, feed specification tolerance, and controllability, which all favour fluid bed and CFB gasifiers. A 10 MWe IGCC system for example might require one CFB gasifier but four fixed-bed gasifiers, although the overall costs may be similar. The advantages and disadvantages of the different types of gasifier have been described earlier; systems that are currently available or are being developed are summarized later. It can be concluded that there are no perceived obstacles to successful demonstration of an advanced biomass gasifier.

Ash removal. The quantity of ash requiring removal and disposal from a biomass gasifier is relatively small, typically 1–2% of the dry feed weight. Removal from the gasifier will vary according to the type of system. Fixed beds will usually have a rotating grate with screw or other mechanical discharge from the base of the reactor. Fluid beds may have an overflow arrangement or extraction from the bed as a 'bleed', while circulating fluid beds will take off a sidestream from an appropriate place in the circuit. Each process has its own proprietary system. Reliability depends on the experience gained by the developer and the mode of ash removal.

Secondary and tertiary ash removal arises from cyclones, hot gas filters and water washing systems. Apart from hot gas filters, were little operating experience has been obtained, these are well understood and reliable.

Heat recovery. The product gas is usually hot, ranging from ~800°C to 1100°C. It will need to be cooled before a hot gas filter to ~500–600°C, or even lower if water washing is the first gas cleaning step. This provides the opportunity to recover heat as steam for combined-cycle operation; up to 10% of the total energy content of the feed might be recovered. Particular care is needed to avoid tar deposition or fouling of the heat exchanger surfaces with ash, char or any other contaminants. Primary raw gas cleaning is thus very important. The specification of the entire heat recovery and gas cleaning train requires careful evaluation and optimization, and generalization other than identification of problems is not possible. The most convincing evidence of plausible design lies in data from extensive operation, with a quantitative appreciation of deviations from ideality.

Gas cleaning

This section of the overall system has received the least exposure to large-scale and long-term operation. It must therefore be considered the least certain aspect of the system.

Much has been written and assumed about the effectiveness and performance of hot gas filters that cannot be substantiated for biomass-based systems. This is probably the least developed aspect of the entire system. There is no long-term or large-scale operating experience. Claims for effectiveness and the consequences of failure of such devices will require careful evaluation.

There is no clear view as to whether tar cracking or tar removal is preferable, although the current trend is to prefer cracking to reduce potential tar deposition problems and minimize washing water requirements. Pressurized systems rely on high temperatures for tar cracking or catalytic tar cracking with hot gas filtration to deliver as hot a gas as possible to the turbine combustor and maximize efficiency, also considering the temperature requirements for alkali metal control and materials of construction of the filters. This maximizes the energy efficiency of the system but combines several unproven or inadequately proven concepts. The high operating pressure also avoids the need for a fuel gas compressor, thus avoiding the need for a cool gas to compress before combustion. Atmospheric pressure systems have fewer constraints but may require the fuel gas to be compressed before combustion, in which case more cooling is required. At least one system advocates

the use of both tar cracking and removal to ensure that a sufficiently clean gas is delivered to the turbine. For engine applications, a clean cold gas is required, but not to the purity requirements of a turbine. Water washing may be adequate, depending on the gasifier.

Heat may be recovered from the hot product gas at several stages. Recovery from the raw gas is described above. Some further heat may be recovered after the hot gas filter, but this is of lower grade, although for larger plants a more sophisticated water–steam cycle may be justified on a countercurrent principle. Low-temperature heat is worth recovering only if there is a good local market for it. Careful optimization of the total heat system is necessary to obtain the high efficiencies promised for combined-cycle plants.

Water treatment will be required if there is wet washing or if there are any condensates from the process. Although it is believed that most organics can be satisfactorily processed in conventional biological treatment systems, there is a paucity of data to support this claim[13]. However, if there is a water scarcity and intensive internal recycling is used, giving more concentrated wastewaters, then there is a potential problem with phenols and related biologically intractable compounds. These may require incineration or other disposal.

Table 12 earlier provided a list of contaminants and a possible specification for a turbine. Engine requirements would be much more relaxed. In neither case are there robust data available. Current experiences with ongoing projects will provide better guidelines, but until a turbine is installed and its performance carefully monitored, there will only be informed speculation about specifications. Even then, there will be a trade-off between more stringent and costly gas cleaning and the higher maintenance costs of a turbine, which will require careful optimization.

Power generation

Gas compression. Established turbosets are designed on the assumption that the compressor throughput matches the turbine throughput, with small allowances made for fuel addition in the combustion chambers and air bleeds from the compressor for blade cooling. The low energy density of gases of low heating value means that the volume of fuel injected will be substantial. In cases where the gasifying medium is taken from the turbine compressor this is not expected to be a problem. However, where the gasifying medium is provided independently, there will be a large difference between compressor and turbine throughputs owing to the addition of fuel gas, which will require redesign of the turboset to match the compressor with the turbine.

There is a potential problem when using the turbine compressor to supply the gasifier, whereby loss of output from the gasifier will mean loss of power at the turbine and thus loss of power to the comrpressor supplying the gasifier. Such a situation could rapidly shut down the system. Advanced control systems, possibly with auxiliary firing, would be needed to reduce this risk. Alternatively additional and/or oversized compressors can be used, both of which increase cost and reduce performance. Compressors are well-established technology. However, there are uncertainties in this application in the potential mismatch between turbine and compressor, and in the design of an adequate control system.

Gas turbine. Gas turbine manufacturers have produced turbines fuelled by lean gases such as those produced in steel smelting. These tend to be large industrial units that are more tolerant of contaminants but have lower efficiencies than aero turbines. Design work and trials are under way with aero turbines, but there are no commercial applications with lean gases derived from biomass. Although turbine manufacturers are confident that the combustion of lean gases is technically feasible, some uncertainty will remain until this is proven. Some auxiliary fuel capability would be beneficial at start-up and at times when the gasifier is unavailable or product gas output is limited. This would require redesign of fuel burners, which is again assumed to be technically feasible but at the expense of additional design cost and uncertainty with operation of a multifuel combustor.

The importance and uncertainty of gas cleanup have been noted above. It should be remembered that turbines of the scale likely to be used for biomass applications will be smaller than the $\geqslant 100$ MWe units usual in natural-gas-fired or coal-gas-fired applications, owing to the inherent scattering of biomass production. This significantly increases transportation costs as size increases, to the point where biomass production is not economic or technically feasible. For example, a 10 MWe IGCC system will require an area of ~ 5000 ha in northern Europe to produce sufficient biomass, which is represented by a forest of 8 km diameter consisting of 100% trees. A more typical forest would be at most 50% trees, and cover an area of 10 000 ha or nearly 12 km diameter.

This reduced capacity means that turbine components are more susceptible to damage from fuel contaminants, as the protective layers are necessarily thinner. This is exacerbated by the high volume of fuel that is required. Turbine reliability is therefore closely related to the effectiveness and reliability of the gas cleanup system.

Complete combustion of the fuel may be difficult to achieve, which would result in high hydrocarbon emissions. This problem can be solved by increasing the size of the combustion chambers, which will add to the design cost of the turbine. Again, the solution is assumed to be technically feasible but unproven.

It is generally agreed that thermal NO_x emissions are unlikely to be a problem, because of the low flame temperature. However, fuel-bound nitrogen could cause substantial NO_x emissions unless action is taken to remove the nitrogen compounds from the fuel or NO_x from the flue gas.

Engines. The use of lean gases such as landfill or digester gas in gas engines is well developed, and machines exist that can be used in this application. Their disadvantage lies in the low-quality waste heat that is generated as a result of engine cooling and from exhaust gases. This makes application in combined-cycle mode unlikely. Operation in cogeneration (CHP) mode is more accepted. Engines also have the advantage that they can be run on a variety of fuels or fuel combinations with relatively minor adjustment. Gas cleaning is very

important, although engines are considered to be less sensitive to contaminants than are gas turbines.

The main uncertainty with engines is an economic one. Electrical efficiencies of engines at the rating required are higher than those of turbines in simple-cycle mode. When turbines are operated in combined-cycle or STIG modes they become much more competitive in terms of electrical efficiency, although the systems naturally become more complex and expensive. Also there is a far greater potential for waste heat in a gas turbine cycle than in engine cycles. Thus there is some uncertainty about the choice between turbines and engines at the likely scale of a biomass-based unit of 5–30 MWe.

Steam generation. Steam generation is an established technology and there are few problems associated with it, other than the design of the system to make best use of the available waste heat. However, there is still a risk of corrosion if removal of sulfur and chlorine compounds from the product gas is inadequate.

The use of steam in combined cycles is established in large-scale generating systems. Application at the scale required is technically feasible, although it may not be economic owing to the diseconomy of scale at low outputs. There is also the drop in efficiency of lower-capacity plants which exacerbates the scale effect. The point at which a combined cycle is no longer economic is not known, but attention is drawn to the need to establish the viability of a cogeneration system in comparison with an open cycle and not assume that the increased efficiency justifies the additional cost. Data were presented earlier to show the effect of scale in power generation.

The use of steam in STIG cycles is commercially accepted for high-grade fossil fuel applications but has not been tested when firing with lean fuels. In the latter case, steam injection could make combustion unstable, and may also increase the turbine throughput to above its maximum capacity. Hence STIG, though offering substantial electrical efficiency improvements at a lower cost than combined cycles, must be viewed with some uncertainty.

Steam production from waste heat from engines is also established, although only low pressure steam could be generated.

Heat recovery. The use of exhaust heat to preheat compressed air in a gas turbine cycle will require a high-temperature ceramic gas–gas heat exchanger. The application of ceramics in heat exchangers is an emerging technology and therefore this option is uncertain. Again the importance of gas cleaning to prevent fouling at the heat exchanger surfaces must be emphasized.

EXISTING GASIFICATION AND POWER GENERATION SYSTEMS

Recent and current biomass gasification-to-electricity systems were summarized in *Table 8*; the major gasification groups and their activities were listed earlier in *Table 9*. A comprehensive review of all these technologies has recently been published[6].

CONCLUSIONS

The process components involved in an integrated biomass-to-electricity system have all been individually tested at pilot scale or larger, but long-term operation and integration can be achieved only with substantial demonstration plant. Several processes are in hand and more are planned for implementation in the near term. The key conclusions from this study are summarized below:

1. The stage of development of biomass gasifiers is sufficiently advanced to justify a substantial demonstration plant to prove the total IGCC concept and obtain reliable performance data. There are still areas of uncertainty, but these are relatively minor and will not be resolved until and unless a large integrated plant is built.
2. Gas cleaning has been developed in the laboratory to the point where large-scale demonstration and long-term operating experience are necessary. This area can be considered the least developed and most likely to create problems in a demonstration plant.
3. Biomass handling, storage, drying, comminution and screening are well established in the pulp and paper industry, as well as combustion systems world-wide, and present no uncertainties in operation and performance. There is a need to optimize the cost and

Table 18 Gasification-to-electricity systems

Gasifier	Host organization	Technology	Location
Europe			
Ahlström	Bioflow	Pressure CFB	Sweden
Lurgi	ENEL	CFB	Italy
Tampella	Elsam	Pressure FB	Denmark
TPS	Aerimpianti	CFB	Italy
TPS	Yorkshire Water	CFB	UK
VUB	VUB	FB	Belgium
Wellman	Border Biofuels	Updraft	UK
North America			
Battelle Columbus	Battelle Columbus	Multi-solid FB	USA
GE	General Electric	Updraft	USA
IGT	PICHTR, Hawaii	Pressure oxygen FB	USA
JWP (EPI)	North Powder	FB	USA
MTCI	MTCI	FB	USA

performance of the front end of the plant in relation to the gasifier performance and requirements, and the availability of heat and power energy from the cleanup and power generation stages.

4. Turbine fuel specifications are imperfectly defined. There are various requirements promoted by manufacturers that have not been substantiated in tests. There will be a trade-off between higher levels of gas cleaning and higher maintenance costs that can only be resolved by large-scale and long-term operation.
5. Engine fuel specifications are imperfectly defined. The level of uncertainty is lower than for gas turbines. Engines exist that can be, and have been, readily adapted to run on biomass-derived gases. However, fuel specifications are currently produced on an *ad hoc* basis.

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